A-2000-28
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EPA-450/3-80-009b

Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities

U.S. ENVIRONMENTAL PROTECTION AGENCY
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November 1980

PREFACE

Part I provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis, and establishing emission limitations for BART. Part II contains an explicit discussion of the engineering analysis required by Part I. Part II is primarily for the analysis of fossil fuel-fired power plants with a generating capacity in excess of 750 MW. The procedures outlined in Part I, however, may be used for other existing stationary facilities as well.

PART I

GUIDELINE FOR DETERMINING

BEST AVAILABLE RETROFIT TECHNOLOGY

PART I. GUIDELINE FOR DETERMINING BEST AVAILABLE RETROFIT TECHNOLOGY

PART I. GUIDELINE FOR DETERMINING BEST AVAILABLE RETROFIT TECHNOLOGY

1.0 INTRODUCTION

Section 169A of the Clean Air Act, as amended in 1977, calls for the protection of visibility in mandatory Class I Federal areas where visibility is an important value.* Section 169A specifically requires affected States to remedy existing visibility impairment, in part, through installation of Best Available Retrofit Technology (BART) for certain existing stationary facilities.

EPA has promulgated regulations to be codified at 40 CFR 51.300 *et seq* that implement §169A. BART determinations must be performed on a case-by-case basis considering such factors as the energy, environmental, and economic impacts of alternative control systems. This document provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis of available control systems, and establishing emission limitations for BART. The States must determine emission limitations for fossil fuel-fired power plants with a total generating capacity in excess of 750 megawatts pursuant to this guideline, which reflects EPA's conclusion that the controls needed to meet the new source performance standard (NSPS) for power plants (40 CFR Part 60, Subpart Da) are generally available to these sources. The procedures outlined herein are also appropriate for any other existing major stationary source.

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*These areas are listed in 40 CFR Part 81, Subpart D. From this point forward, they will be referred to as mandatory Class I Federal areas.

1.1 BACKGROUND

Congress was concerned with the impairment of visibility in the nation's parks and wilderness areas, but it realized remedying existing impairment in these areas could not be reasonably accomplished overnight. In order to assure that BART requirements will not be unduly burdensome or costly, several provisions were included in Section 169A. These are:

(1) BART may not be required by the Administrator for existing stationary facilities which have been in operation for more than fifteen years as of August 7, 1977 unless the source was reconstructed after August 7, 1962.

(2) BART for fossil-fuel fired power plants with a generating capacity in excess of 750 megawatts must be determined pursuant to EPA guidelines.

(3) The Administrator may exempt from BART requirements those sources he determines do not cause or contribute to significant visibility impairment in a Class I area. This exemption may not apply to fossil-fuel fired power plants 750 megawatts or greater unless it is demonstrated to the Administrator that the facility is located at such a distance from a Class I area as not to cause or contribute to significant visibility impairment in any such area. Any exemption from BART will be effective only upon concurrence by the appropriate Federal Land Manager.

(4) In determining BART for any existing stationary facility, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility anticipated to result from application of controls shall be considered.

1.1.1. Pollutants of Concern

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. NO_2 is a light-absorbing gas and generally causes reddish or yellow-brown atmospheric discoloration because it absorbs light at the blue end of the spectrum. Primary particulates and secondary aerosols, formed from emissions of SO_2 and NO_x, scatter light away from and into an observer's line of sight causing a reduction in visual range and atmospheric discoloration. These three pollutants (primary particulates, NO_x, and SO_2) have been identified as the primary contributors to visibility impairment. Detailed background information can be found in "Protecting Visibility: An EPA Report to Congress."*

1.1.2 Phased Program

EPA has established a phased approach to visibility impairment. Phase I focuses on controlling those sources which can currently be identified as causing visibility impairment. Phase I visibility impairment primarily includes visible plumes emitted from stacks, and single source haze. Smoke, dust, or colored gas plumes obscure the sky or horizon. Single source haze causes a general whitening of the atmosphere and reduction of clarity of terrain features. Both forms of impairment when "reasonably attributed" to a source must be regulated under Phase I. As our scientific and technical understanding of source/impairment relationships improves, future regulations will address more complex forms of visibility impairment such as regional haze and urban plumes.

*This report is available through the National Technical Information Service, 5258 Port Royal, Springfield, Virginia 22161.

This guideline is directed toward Phase I analyses. Although the number and kind of sources and the type of pollutants included in future BART analyses may expand, the procedures outlined herein are unlikely to change substantially. In performing BART analyses the State should be cognizant of possible future requirements which could be imposed on sources as a result of later phases of the program. For example, a major power plant may have a coherent plume caused by primary particulate emissions which must be analyzed under Phase I, and also contribute to regional haze through emissions of sulfur dioxide which will be addressed in later phases. Under Phase I, the source would be analyzed for BART with respect to TSP because it causes visibility impairment in the form of a distinct plume. However, since the source may also contribute to a regional haze, the State would be well advised to also analyze control systems for SO_2 to determine if a single system could more efficiently control both pollutants than two separate systems and to evaluate whether alternative TSP control systems would be compatible with future application of control systems designed to control a different pollutant (e.g. SO_2). The State is not required to impose SO_2 controls in this situation. However, EPA intends at present that physical constraints, incompatible particulate control, etc. resulting from limitations on Phase I requirements will not serve as justification for not imposing SO_2 controls under Phase II.

PROCEDURES FOR IDENTIFYING SOURCES FOR BART ANALYSIS

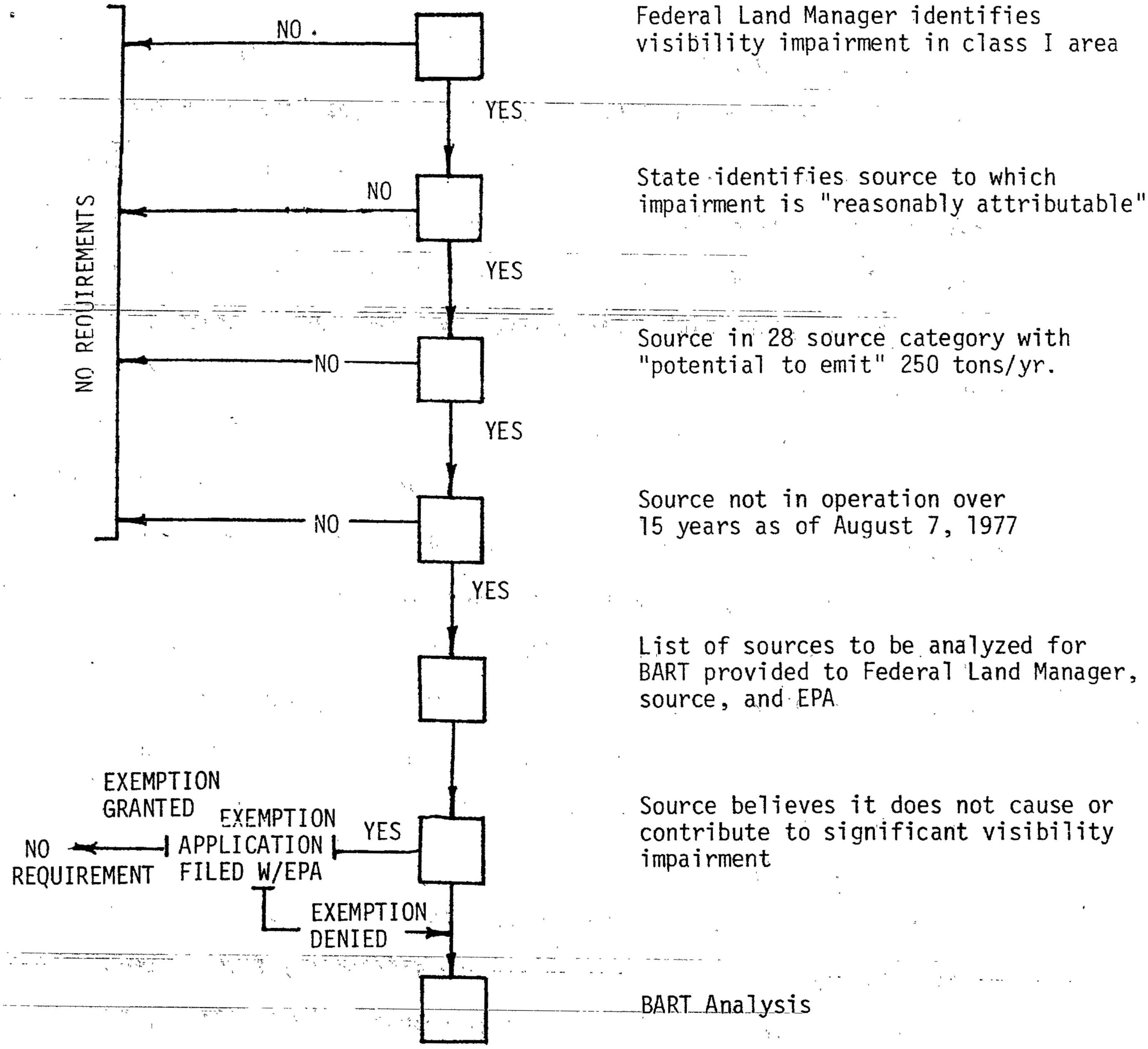

Figure 1

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1.2 IDENTIFICATION OF A SOURCE IMPAIRING VISIBILITY

See Figure 1.

If a Federal Land Manager identifies visibility impairment in a Class I area, the State must first determine, if possible, by visual observation or any other monitoring technique it deems appropriate, the existing stationary facility to which the impairment is reasonably attributable. In other words, for the purposes of Phase I of the visibility program, States need only identify impairment that can be physically traced to a source.

States can use visual observation (either ground-based or with an aircraft) or any other technique it deems appropriate to determine which source causes the visibility impairment. An "Interim Guidance for Visibility Monitoring", * is available and describes current monitoring methods. It is available through the National Technical Information Service. Once the impact of the existing stationary facility on visibility is identified as being reasonably attributable to that source, the State must conduct an analysis to determine BART for that particular existing stationary facility.

The Act limits the requirement for the installation of BART to those existing stationary facilities which started operation after August 6, 1962, and were existence as of August 7, 1977. An existing stationary facility is any source which meets these requirements, is listed in Table 1, and has a potential to emit 250 tons per year, or more, of any air pollutant causing or contributing to visibility impairment.

A source which believes it does not cause or contribute to significant visibility impairment in a Class I area may apply for an exemption from BART. The exemption application must be submitted to the Administrator

*"Interim Guidance for Visibility Monitoring," U.S. Environmental Protection Agency EPA-450/2-80-082

TABLE 1

"EXISTING STATIONARY FACILITY"

fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
coal cleaning plants (thermal dryers),
kraft pulp mills,
Portland cement plants,
primary zinc smelters,
iron and steel mill plants,
primary aluminum ore reduction plants,
primary copper smelters,
municipal incinerators capable of charging more than 250 tons of refuse per day,
hydrofluoric, sulfuric, and nitric acid plants,
petroleum refineries,
lime plants,
phosphate rock processing plants,
coke oven batteries,
sulfur recovery plants,
carbon black plants (furnace process),
primary lead smelters,
fuel conversion plants,
sintering plants,
secondary metal production facilities,
chemical process plants,
fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
taconite ore processing facilities,
glass fiber processing plants,
charcoal production facilities

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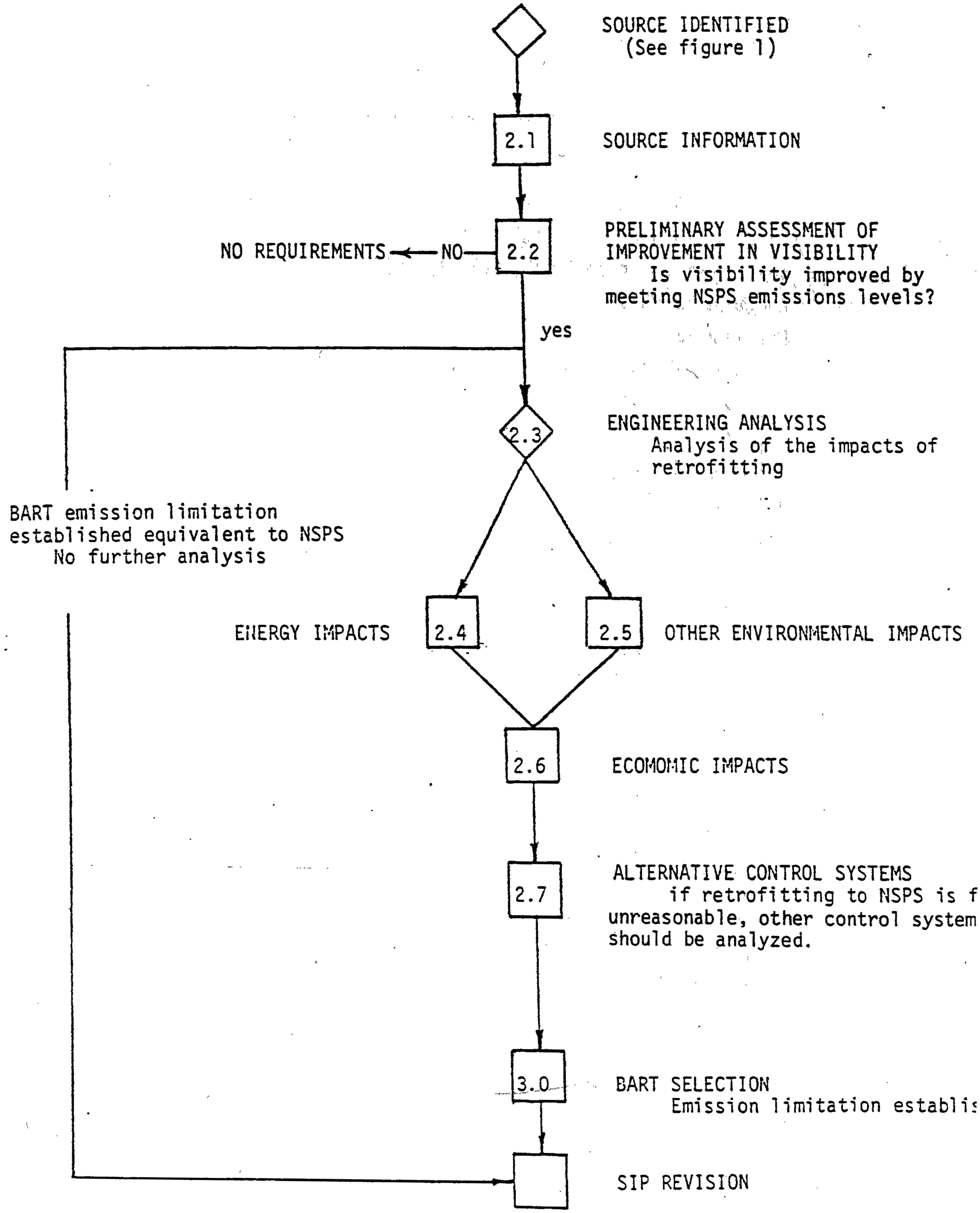
SOURCE IDENTIFIED
(See figure 1)
2.1
SOURCE INFORMATION
2.2
NO REQUIREMENTS
NO
PRELIMINARY ASSESSMENT OF IMPROVEMENT IN VISIBILITY
Is visibility improved by meeting NSPS emissions levels?
yes
2.3
ENGINEERING ANALYSIS
Analysis of the impacts of retrofitting
BART emission limitation established equivalent to NSPS
No further analysis
ENERGY IMPACTS
2.4
2.5
OTHER ENVIRONMENTAL IMPACTS
2.6
ECOMOMIC IMPACTS
2.7
ALTERNATIVE CONTROL SYSTEMS
if retrofitting to NSPS is f
unreasonable, other control system
should be analyzed.
3.0
BART SELECTION
Emission limitation establi
SIP REVISION

Figure 2

according to procedures outlined in 40 CFR 51.303. The Administrator, after appropriate public review, will grant or deny the exemption. Any exemption is only effective upon concurrence by the Federal Land Manager.

2.0 VISIBILITY IMPACT ANALYSIS

See Figure 2.

Upon identifying the existing stationary facility to which the visibility impairment is reasonably attributable, a BART analysis for the pollutant(s) causing the impairment must be performed. A visibility impact analysis is the first step necessary to determine if visibility is anticipated to improve from the imposition of retrofit controls. The following sections discuss how this is accomplished.

2.1 PROCEDURES

2.1.1 Source Information

In order to conduct a visibility analysis the following data are needed.

1. Plant size, capacity, mode of operation
2. Emission rates (actual and potential) for nitrogen oxides (NO_x), particulates, and sulfur dioxide (SO_x), (grams per second)
3. Remaining useful life of any existing pollution control systems
4. Remaining useful life of any specific units within the plant
5. Remaining plant life
6. Stack diameters (meters)
7. Stack heights (meters)
8. Actual gas velocity (meters per second)
9. Stack temperature (degrees Kelvin)

The above data should be obtained from the plant and should be confirmed by other data available to the State from in-house, Federal, and local agency records. Data for full load conditions should be used for preliminary visibility impact analysis. For visibility impact analyses in conjunction with evaluation of BART alternatives, variations in emission rates with changes in production may be considered if reliable data are available. Other parameters which may also be useful are opacity measurements and particle size distribution of emissions.

2.1.2 Emission Rate Estimates

A representation of current, actual emission rates, i.e., emission rates with any existing control systems, is necessary so that the expected improvement in visibility can be estimated. These emission rates can be obtained from various places such as the source itself, other control agencies, in-house data, or new emission test data. They should represent actual emissions and not estimates based upon theoretical control efficiencies.

This data should be thoroughly analyzed for its accuracy based on present plant conditions. If the emission rates do not seem appropriate in light of the observed visibility impacts, the State should require additional emission tests, and/or calculate a current emission rate considering present plant processes, air pollution control systems currently in use, and current fuel input. The differing emission rates should then be compared and, using good engineering judgment, the one which most accurately represents the current emission rate of the source should be used.

2.2 PRELIMINARY ASSESSMENT OF IMPROVEMENT IN VISIBILITY

After all appropriate data are collected and emission rates established, the amount of improvement in visibility expected from retrofitting must be assessed. This is accomplished by comparing the existing visibility (based on existing emissions) with the visibility anticipated from imposition of the maximum achievable control. Maximum achievable control is generally represented by New Source Performance Standards as published in 40 CFR Part 60, applicable to the source under analysis. If the visibility impact analysis shows visibility improves a perceptible amount under this level of control,* the BART analysis then begins to consider alternative retrofit control schemes for the source. If, after comparison of the visibility at existing and maximum achievable control levels, no perceptible improvement is expected, the analysis need not continue. Additionally, if the State chooses to impose a BART emission limitation equivalent to the NSPS the analysis need not continue.

Both analytical techniques and empirical methods may be used to estimate the degree in improvement in visibility anticipated from control of certain pollutants. Analytical techniques which assess visibility at various emission levels are now being refined by the Agency. Two guideline documents, "Workbook for Estimating Visibility Impairment" and "User's Manual for the Plume Visibility Model (PLUVUE)," discuss a useful analytical technique to aid in assessing improvements in visibility at various control levels. These documents have undergone public review and are available through NTIS. Although this technique has yet to be fully validated, preliminary results using data from EPA's VISTTA program are promising, and the Agency believes this to be a valuable

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*Preliminary studies indicate a change in contrast in the range of 0.01 to 0.04 is capable of being perceived by a human observer. [See Protecting Visibility: An EPA Report to Congress.]

part of the decision-making process. Use of these two guideline documents is not, however, required. States which in their discretion use the guidelines should not consider any results obtained exclusively, but should consider this information together with all other available information in making a regulatory decision.

Empirical methods, i.e. comparison photographic techniques, can also provide valuable input into the sum of information on which to base a BART decision. A discussion of this technique follows.

2.2.1. Primary Particulates

Primary particulates are one of the major causes of visibility impairment generally observed in the form of a distinct plume. The visibility impairment caused by a primary particulate plume is usually localized and can generally be traced back, by visual observation or monitoring, to its source. The improvement anticipated from controlling primary particulate emissions is (1) the plume disappears, (2) the effect becomes even more localized, (3) the effect is reduced perceptibly or (4) the frequency of the impairment decreases so as to improve visibility. A common sense approach using comparison photographic techniques could adequately demonstrate the impact of controlling emissions for the purposes of Phase I BART determinations. These photographic techniques would involve comparing the effects caused by a well controlled source versus those caused by the source under consideration. This comparison would be of similar sources of equivalent size under similar meteorological and geographical conditions. For example, if a similar source has applied a certain primary particulate control and its plume disappeared, or the impairment was reduced, the source could be used as an example of the amount of improvement expected by application of that control technology. For a more specific discussion of the proper use of photographs, see Section 3.3.3 of the "Interim Guidance for Visibility Monitoring."

A more precise analysis of the effects of particulate matter on visibility is accomplished through the use of mathematical and other analytical techniques. The State may use these techniques at their discretion. However, the Agency is not requiring their use. The workbook and User's Manual referenced in the previous section describe these techniques.

2.2.2 Oxides of Nitrogen

Another major component of visibility impairment is NO_2. Gaseous NO_2 absorbs blue light creating a reddish or yellowish-brown plume. NO_x can also act as a precursor of light scattering aerosols. As with primary particulate plumes, the NO_x plume is usually localized and can generally be traced back, by visual observations or monitoring, to its source.

Current techniques for reducing NO_x emissions may show some improvement in visibility, but evidence shows such techniques generally do not reduce emissions sufficiently to render the plume unobservable or provide substantial improvement in visibility. New, more effective control techniques, at present available only under limited circumstances, should become available within the next few years. Section 51.302 of the regulations requires States to reanalyze any pollutant (such as NO_x) that has not previously been controlled by BART when the Administrator determines that new, more effective control technology is available.

As with particulate matter, a precise analysis of the effects of NO_x is accomplished with the analytical techniques mentioned previously.

2.2.3 Sulfur Dioxide

Sulfur dioxide does not directly affect visibility, but is a precursor of light scattering aerosols. These fine particles, (sulfates) by scattering light in the observer - target path, reduce the contrast and, therefore the clarity and detail, between the target and its background. This general reduction in contrast caused by sulfate aerosols is most often associated with regional haze, which will be dealt with under Phase II, but sulfates can and do contribute to visible plumes and single source haze. If the visibility impairment is "reasonably attributable" to the source, as may be the case in isolated, rural environments, the source should be required to implement BART to reduce SO_2 emissions where improvement in visibility is anticipated. However, since SO_2 is most often a contributor to regional haze, an existing major facility that emits SO_2 will generally not be subject to BART for that pollutant for the first phase of the visibility program.

Analytical techniques are needed, but not required, for a precise analysis of SO_2 and its effects on visibility. The Workbook and User's Manual referenced previously provides information on this.

2.2.4 Other Factors To Be Considered

Frequency, duration, and time of occurrence refer to how often an impairment impacts a class I area, how long this impairment lasts, and when the impairment occurs. Relative improvement such as the model predicts will not always present all the benefits that can be obtained. For example, the model may show an overall improvement in sky-plume contrast of 10 percent from worst case impairment, but this may be sufficient to reduce the frequency of the impairment so that its impact is substantially reduced during period of maximum visitor use. Oftentimes, a reduction in frequency and duration will provide a maximum benefit for a minimum control effort. Thus, the temporal extent of the impairment is of great importance and should be considered when assessing anticipated improvements in visibility.

2.3 ENGINEERING ANALYSIS

If visibility is expected to improve as a result of the imposition of controls, available retrofit control systems should be analyzed so that an emission limitation representing BART can be established. BART determinations must be based on the cost of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, any existing air pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement reasonably anticipated to result from the use of such technology.

A general discussion of the economic, energy, and nonair environmental impacts which should be considered is found in the following sections. For the engineering analysis required by this part, information specific to coal fired power plants is found in Part II. Part II provides information on selecting alternative retrofit systems, and assessing the economic, energy, and environmental impacts of retrofit alternatives.

2.4 ENERGY IMPACT

Energy impacts should address energy use associated with the control system under investigation and the direct effects of such energy use on the facility and the community. Some specific considerations for energy impacts are presented below.

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2.4.1 Energy Consumption

The amount, type (e.g., electric, coal, natural gas), and source of energy required by the control system under consideration should be identified and compared. In analyzing for energy consumption, comparisons can be made in terms of energy consumption per unit of pollution removed (for example, Btu/ton particulate removed).

2.4.2 Impact on Scarce Fuels

The type and amount of scarce fuels (e.g., natural gas, distillate oil) which are required to comply with the control requirement should be identified and compared. The designation of a scarce fuel may vary from area to area, but in general a scarce fuel is one which is in short supply locally and can better be used for alternative purposes, or one which may not be reasonably available to the source either at present or in the future.

2.4.3 Impact on Locally Available Coal

A control system which requires the use of a fuel other than locally or regionally available coal should be discouraged if such a requirement causes significant local economic disruption or unemployment.

2.5 ENVIRONMENTAL IMPACT

The net environmental impact associated with the emission control system should be determined. Both beneficial impacts (e.g., reduced emissions attributed to a control system) and adverse impacts (e.g. exacerbation of another pollution problem through use of a control system) should be discussed and quantified. Indirect environmental

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impacts (such as pollution impacts at an off-site plant which manufactures chemicals for use in pollution control equipment) normally need not be considered. Some specific considerations are presented below.

2.5.1 Air Pollution Impact

The impact of air pollutants emitted from a gas stream or a fugitive emission source can be assessed in terms of either quantity of emissions, modeled effects on air quality, or both. If application of a control system directly removes or releases other air pollutants (or precursors to other air pollutants), then the pollutants affected and the impact of these emission changes should be identified. The analysis can consider any pollutant affecting air quality including pollutants which are not currently regulated under the Act, but which may be of special concern regionally or locally.

2.5.2 Water Impact

Relative quantities of water used and water pollutants produced and discharged as a result of use of the emission control system should be identified. Where possible, the analysis should assess their effect on such local surface water quality parameters as pH, turbidity, dissolved oxygen, salinity, toxic chemical levels and any other important considerations, such as water supply, as well as on groundwater. The analysis should consider whether applicable water quality standards are met and the availability and effectiveness of various techniques to reduce potential adverse effects.

2.5.3 Solid Waste Disposal Impact

The quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as the result of the application of an alternative emission control system, if considered, should be compared with the quality and quantity of wastes created if the emission control system proposed as BART is used. The composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of sub-surface waters or aquifers should be considered. The relative effectiveness, hazard and opportunity for solid waste management options, such as sanitary landfill, incineration, and recycling, should be identified and discussed.

2.5.4 Irreversible or Irretrievable Commitment of Resources

The BART decision may consider the extent to which the emission control system may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the system may result in irreversible or irretrievable commitment of resources (for example, use of the scarce water resources).

2.6 ECONOMIC ANALYSIS

This analysis should address the economic impacts associated with installing and operating control systems under consideration for BART. Costs associated with New Source Performance Standards can be found in the NSPS Background Information Documents. Other economic impacts which should be considered follow.

2.6.1 Direct Costs

The direct cost for a control method should be presented. Investment costs, operations and maintenance costs and annualized costs should be presented separately. Costs should be itemized and explained. Credit for tax incentives should be included along with credits for product recovery costs and by-product sales generated from the use of control systems. The lifetime of the investment should be so stated. The costs of air treatment, water treatment, and solid waste disposal should be presented separately. When considering the addition of control equipment to that already in place, the cost of incremental control should be analyzed. Additionally, the expected useful life of any existing control equipment should be evaluated on the basis of its expected retirement/ replacement schedule.

As a guide in determining when control costs become excessive, comparisons can be made in terms of certain cost effectiveness ratios. Such ratios may include the following:

- ratio of total control costs to total investment costs
- cost per unit of pollution removed (for example, dollars/ton)
- unit production costs (for example, mill/kw-hr, dollars/ton).

In some cases, the unit of production output may be difficult to determine, as in the case of a plant producing many different products. In such cases, unit production costs can be expressed as cost per dollar of total sales.

The remaining useful life of the source will have an effect on the amortized cost of the anticipated control equipment and, as such, should be given strong consideration in determining BART.

2.6.2 Capital Availability

Capital availability addresses the difficulty that some sources may face in financing alternative control systems. Proof of such claims should be fully documented.

2.6.3 Local Economic Impacts

Local economic impacts address the economic feasibility of BART requirements and the impact on production decisions of the firm in response to the level of control. For example, BART could alter the economics of the plant to the point where the decision would be made to cancel expansion of a facility, to reduce the scale of operation, or to change the production mix. The local employment effects, including number of jobs, dollars paid in salaries, and changes in employee skill levels required should be evaluated. The guideline does not imply that the BART decision should force a plant to the brink of shutdown. The BART decision must be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts.

2.7 CONSIDERING ALTERNATIVE CONTROL SYSTEMS

As previously stated, for fossil fuel fired power plants with a generating capacity in excess of 750 megawatts, the Agency believes that the NSPS level of control can be met with technology that is generally available to these sources, and that this level of control generally represents the best these sources can install as BART.

In determining BART, and for inclusion in its SIP, the State must explain in detail how it weighed the various BART factors required by the Act (§169A(g)(2)), the regulations (§51.301(c)), and this guideline. This explanation must demonstrate that the emission limitation chosen (if one other than the NSPS) reflects a reasonable balance of the various BART factors. This explanation must set forth the visibility, energy, economic, and other impacts associated with application of an NSPS level of control, and compare those impacts to alternative levels of control

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including the level of control selected by the State as BART. Because EPA believes that NSPS control generally represents the best these sources can install as BART, if the State sets for a pollutant emitted by a fossil fuel fired power plant with a generating capacity in excess of 750 megawatts a BART emission limitation equivalent to the NSPS level of control, this detailed demonstration will not be required for the purposes of EPA review.

3.0 BART SELECTION

An emission limitation that is BART must be established for each source. This along with all evidence as to why this emission limit was chosen is incorporated into the SIP submitted to EPA for approval. It is suggested that if a range of alternative control systems were examined, the State arrange these alternatives into an array. This array would include a description of each alternative considered, the cost of the alternative, the improvement in visibility obtained, and any economic, energy, on nonair environmental factors which affect the selection. This array would provide a logical sequence by which the BART emission limitation was set. The State must also present the logic network used in its final decision making process.

PART II

RETROFIT GUIDELINES FOR

COAL-FIRED POWER PLANTS

This report has been reviewed by the Office of Air Quality Planning and Standards, Office of Air, Noise, and Radiation, Environmental Protection Agency, and approved for publication. Mention of company or product names does not constitute endorsement by EPA. Copies are available free of charge to Federal employees, current contractors and grantees, and non-profit organizations - as supplies permit - from the Library Services Office, MD-35, Environmental Protection Agency, Research Triangle Park, NC 27711; or may be obtained, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfeild, VA 22161.

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PART II

SECTION 1

BACKGROUND INFORMATION

1.1 INTRODUCTION

This part of the proposed BART guideline is for use in assessing the effectiveness of retrofit control techniques and for estimating cost. They are flexible with respect to specifying control systems for implementation of BART.

1.2 RELATION TO PART I

Part I provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis, and establishing emission limitations for BART. Part II, as discussed below, contains an explicit discussion of the engineering analysis required by Part I. Part I is general guidance and is appropriate for the analysis of all existing major stationary source categories.

This Part II provides specific engineering information on coal-fired power plants having an operating capacity in excess of 750 megawatts. It provides information for selecting alternative retrofit systems, and assessing the economic, energy, and environmental impacts of retrofit alternatives. Although this part is specifically for coal-fired power plants, much of the engineering information and procedures may be helpful when analyzing sources in other source categories.

1.3 UTILIZATION OF PART II

1.3.1 Purpose

The guidelines in this document specify the emission levels, emission reduction potential, and costs corresponding to each of the retrofit systems discussed. By judicious application of these data to any plant situation, an estimate of cost and effectiveness of a control may be made for that plant. The guidelines are not intended to provide comprehensive cost estimates for retrofitting coal-fired steam generators. Comprehensive cost estimates require extensive engineering studies such as the preparation of specifications, bid criteria, equipment layouts, and detailed drawings. Because the funds needed for these types of studies are usually beyond the budgets of most air pollution control agencies, the broad cost estimating techniques of this document are recommended. The cost estimating data and procedures of this document will generally yield reasonable cost. Should one suspect that the cost estimates of this document would lead to a false conclusion on the cost feasibility of retrofitting certain control systems, the more comprehensive cost (and more costly) estimating techniques previously described should be used. Although the precision of the cost estimates can be improved by more costly studies, the accuracy of conclusions on the effectiveness of the various systems for reducing emissions would generally not be significantly improved by further study.

This document was prepared recognizing that there are techniques other than those used as the basis for this document that are as effective as those used for the cost estimates. Consequently, the owner of a coal-fired steam generator should be allowed to select other techniques as long as such alternate systems perform at a level of effectiveness required by the BART determination.

1.3.2 Data, Assumptions, and Technical Approach

This study resulted from the need to understand the basis and methods of retrofit cost analysis that would cause emission reduction of nitrogen oxides, particulate, and sulfur oxides. The cost modules developed have been based on the emission levels found in EPA background documentation (1, 2, 3, and 4,). These levels are 210 and 260 nanograms per joule heat input (0.5 lbs/10^6 Btu and 0.6x lb/10^6 Btu) for NO_x from subbituminous and bituminous coal respectively; 13 ng/J heat input (0.03 lbs/10^6 Btu) for particulate emissions; and 90% removal of the sulfur oxides from the power plant flue gas. These three pollutants are of prime visibility concern although emissions from large, coal-fired, steam generators also include carbon monoxide, halogens, trace metals, and hydrocarbons (including polycyclic organic matter). As stated in Part 1, it is doubtful that either NO_x or SO_x control will be required in Phase 1 of the visibility program. However, when this report was begun it was felt that control systems for all of the major visibility impairing pollutants should be investigated. All of that information is presented here for reference and future use. The process and cost data were obtained primarily from background information for new source performance standards and from Pullman Kellogg in-house work (1,2,3,4, and 5). The data needed for establishing process requirements to retrofit the example power plants were obtained from information furnished by the power plants, from visual inspection of the plant sites during plant visits, and from yearly reports prepared by the utilities (FPC Form 67).

The methods considered for control of emissions are: boiler modifications for reduction of nitrogen oxide emissions; particulate control using baghouses and/or electrostatic precipitators (hot or cold side); and flue gas desulfurization by either wet or semi-dry scrubbing.

The scope of work was directed to designs for retrofitting power plants with 750 MW, or larger, total plant capacity. However, some of the designs can be applied to much smaller plants. The costs developed here incorporate the variations involved in attaining the plant capacity; therefore, the study accomodates retrofitting most power plants with emission controls.

1.3.3 Content and Limitations

The general content and the costs in this report describe the method and choice of individual retrofit for emission controls. The document also develops a method for determining total retrofit investment and annual operating costs. The content has been developed for engineering personnel use such that the States and Federal government can make best available retrofit technology decisions. It is also intended for use by those interested industry personnel involved in environmental control. The appendices provide examples of retrofit costs and plant layout requirements for three power plants. Reduction in nitrogen oxide formation is achieved by boiler modification only; no other control alternatives have been selected. Particulate emissions control is limited to baghouses and electrostatic precipitators (hot and cold side). The flue gas desulfurization systems are designed for wet or dry scrubbing.

1.3.4 Method of Use

Methods for developing cost data are described in Section 3. The technique for using these cost modules to determine the total retrofit costs for a power plant is described in Section 4. Examples are presented in the Appendices.

1.4 REFERENCES

1. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed NO_x Emission Standards." EPA-450/2-78-005a, July 1978.
2. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed Particulate Matter Emission Standards." EPA-450/2-78-006a, July 1978.
3. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed SO_2 Emission Standards." EPA-450/2-78-007a, August 1978
4. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed SO_2 Emission Standards Supplement." EPA-450/2-78-007a-1, Aug 1979
5. Final report, "Retrofit Guidelines for Coal-Fired Power Plants," Pullman Kellogg Division of Pullman Incorporated, EPA Contract No. 68-02-2619, Work Assignment 13, September 1979

SECTION 2

RETROFIT EMISSION CONTROL TECHNIQUES

2.1 GENERAL

The retrofitting technques for NO_x, SO_2, and particulate emissions considered in this document are based only on commercially available methods for reducing these pollutants. For NO_x, the emission reduction techniques considered include staged combustion (overfire air and/or curtain air) and low NO_x burners. The particulate collection studies examined ESP's (cold or hot side) and baghouses (fabric filters).

The maximum control effectiveness of the systems discussed in this document is as follows:

NO_x

Subbituminous coal	210 nanograms per joule ($0.5\ lb/10^6$ Btu)
Bituminous coal	260 nanograms per joule ($0.6\ lb/10^6$ Btu)

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Particulates

Fabric Filters and Electrostatic Precipitators	13 nanograms per joule ($0.03\ lb/10^6$ Btu)
Scrubbers	21 nanograms per joule ($0.05\ lb/10^6$ Btu)

SO_2

Wet scrubbers	90 percent removal of the SO_2
Dry scrubbers	70 percent removal of the SO_2

As discussed in Section 2.2 and Section 3, it may not always be possible to attain these NO_x levels for all retrofit situations. The EPA position on the operating effectiveness of particulate and SO_2 retrofit control systems is discussed in Appendices D and E of these guidelines.

Control of SO_2 emissions included studies of both wet and semi-dry scrubbing. The costs developed for the wet scrubbing system include cases that use lime or limestone, Wellman Lord, Mag-ox, or double alkali scrubbing. The semi-dry scrubbing (lime) uses the Joy-Niro process. This process uses a spray dryer followed by a baghouse for particulate collection.

The control systems outlined above are discussed in detail in the following sections.

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SECTION 3

RETROFIT DESIGN AND COSTS

3.1 GENERAL

The key pieces of equipment used to retrofit pulverized-coal-fired, steam generators for NO_x reduction and for control of SO_2 and particulates are fixed in operational design. The functional design for sizing to meet emission level requirements reduce relatively easily to physical layout considerations and mathematical analysis. Using the retrofit technology outlined in Section 2, this section presents the guidelines for determining retrofit costs. It also presents the equations for prorating to other design conditions. This is the basis for estimating costs for any desired retrofit situation. A typical schedule for retrofitting these plants concludes the discussion.

3.1.1 Emissions

The cost modules for NO_x reduction are based on the best available technology associated with boiler modifications to reduce NO_x formation. This document presents costs based on these modifications. Emission levels of 210 ng/J heat input (0.5 lb/106 Btu) for subbituminous coal and 260 nanograms per joule heat input (0.6 lbs/10^6 Btu) for bituminous coal are the basis of the modification costs.[1] Actual implementation of the modifications discussed previously may not permit this emission level to be reached, but it presents the best potential for NO_x emission reductions.

The costs for SO_2 control are based on achieving SO_2 reductions in the flue gas of up to 90%.[2] For particulate control, the cost modules are based on achieving emission levels of 13 ng/J heat input (0.03 lb/106 Btu).[3]

3.1.2 Basis of Costs

The costs of an emission control systems are estimated as capital costs and annualized cost. The capital cost represents the initial investment necessary to install and commission the system. All costs are based on 3rd-quarter 1979 dollars. Annualized costs represent the cost of operating and maintaining the system and the charges needed to recover the capital investment, which are referred to as fixed costs. The cost of land for sludge disposal is not included in this study. Land used for sludge disposal is considered to have zero value once sludge disposal at that site has ceased.

Capital costs consist of direct and indirect costs incurred up to the tie-in and startup of the retrofit. Direct costs include the costs of various items of equipment and the labor and material (construction costs including field overhead) required for installing these items and interconnecting the systems. Indirect costs include such items as freight, procurement, and allocated costs associated with the purchase and installation of the control equipment.

3.1.2.1 Direct costs.[4] – The purchased cost of the equipment and the cost of installing it are considered direct costs. The cost of an equipment item is the purchase price paid to the equipment supplier on a free-on-board (f.o.b.) basis; this does not include the freight charges. Installation costs cover the interconnection of the system, which involves piping, electrical, and the other work needed to commission it such as the cost of securing permits and the cost of insurance for the equipment and personnel on site. The costs of foundations, supporting structures, enclosures, ducting, control panels, instrumentation, insulation, painting, and similar items are attributed to installation. Costs including site development, relocation or alteration of existing facilities, administrative facilities, construction of access roads and walkways, and establishing rail, barge, or truck facilities have not been included in developing the retrofit costs except as noted; they must be determined on an individual basis for a specific plant.

3.1.2.2 Indirect costs.[4]– The indirect costs include freight from point of origin and indirect capital costs. The indirect capital costs consist of several cost items which are calculated as percentages of the total installed cost (TIC), the direct costs as noted above. The indirect capital costs include the following items:

A. <u>Interest</u> - Interest covers costs accrued on borrowed capital during construction. (About 10% of the TIC.)

B. <u>Engineering costs</u> - These costs include administrative, process, project, and general costs; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; procurement; travel expenses; living expenses; expediting; inspection; safety; communications; modeling, pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services. (About 10% of the TIC.)

C. <u>Taxes</u> - Include sales, franchise, property, and excise taxes. (About 1.4% of the TIC.)

D. <u>Allowance for shakedown</u> - Includes costs associated with system startup. (About 5% of the TIC.)

E. <u>Spare parts</u> - Represent costs of items stocked in an effort to achieve 100 percent process availability; such items include pumps, valves, controls, special piping and fittings, instruments, spray nozzles, and similar equipment not included in base cost modules. (About 0.5% of the TIC.)

F. <u>Contingency costs</u> - Includes costs resulting from malfunctions, equipment design alternations, and similar unforeseen sources. (About 20% of the TIC).

G. <u>Contractors fee and expenses</u> - Includes costs for field labor payroll, supervision field office, administrative personnel, construction offices, temporary roadways, railroad trackage, maintenance and welding shops, parking lot, communications, temporary piping, electrical, sanitary facilities, rental equipment, unloading and storage of materials, travel expenses, permits, licenses, taxes, insurance, overhead, legal liabilities, field testing of equipment, and labor relations. Contractor fees and expenses are about 5% of the TIC. The indirect cost for a given estimate is about 58.6% of the TIC. Indirect costs have been added to all costs presented in this document.

3.2 RETROFITTING TO REDUCE NO_x EMISSIONS

The effectiveness of applying currently available retrofit control for NO_x emissions to new coal-fired power plants is 210 ng/J heat input (0.5 lbs/10^6 Btu) for subbituminous coal and 260 ng/J heat input (0.6 lbs/10^6 Btu) for bituminous coal.[1] However, these levels may not always be achievable for existing units as a result of intolerable adverse side effects. For new units adverse side effects can be avoided by proper original design, but with existing units it is more difficult to apply the techniques while avoiding effects are discussed in Section 2.2.

Expert advice from steam generator manufacturers and/or combustion engineers is recommended in conjunction with decision making on best available retrofit technology for NO_x control.

3.2.1 Retrofit Techniques for NO_x Control

3.2.1.1 Plant data requirements.- When considering retrofitting a particular boiler for NO_x control in a plant, the following information related to existing boiler design and operation should be gathered:

- o Type of boiler (single-wall, opposed-wall, tangential, or arch-fired)
- o Manufacturer of the boiler
- o Type of existing burners (arrangment, burner type, and burner capacity)
- o Existing NO_x control and monitoring equipment
- o Drawings of burner arrangement,
- o Existing NO_x emissions level and State NO_x emissions limit

SECTION 4

TECHNIQUES FOR ESTIMATING TOTAL RETROFIT COSTS FOR EMISSION CONTROL

4.1 GENERAL

The cost of a power plant retrofit is estimated in terms of capital cost and annualized cost (1). Capital cost represents the initial investment necessary to install and commission the retrofit, and the capital costs consist of the direct and indirect costs that are defined in Section 3.2.1. Annualized costs are composed of direct and fixed charges. Working capital, that is the money required to operate the plant after completion of the retrofit, should also be included in the retrofit cost. Specific cost estimating examples are given in Appendices A, B, and C.

4.2 Working Capital

Working capital is the money set aside to operate the plant after completion of the retrofit. The working capital should be estimated as 25% of the total annual operating costs (direct and fixed).

4.3 Auxiliary Boiler Costs

When plume reheat is required the capital cost of an auxiliary boiler should be included in the total capital cost estimate. Section 3.5.1 describes the techniques that should be used to estimate the size of auxiliary boiler needed. The annual costs of plume reheat steam are included in the annual cost estimates of Table 3.4. Table 4-1 should be used to estimate the capital cost of auxiliary boilers.

TABLE 4-1

CAPITAL AND ANNUAL COSTS (2) FOR AUXILIARY[2] BOILERS GREATER THAN 250 x 10^6 Btu/Hr HEAT INPUT

Capital Cost (a)

	$/$10^6$ Btu/Hr Heat input capacity
Boiler	33,150
Pollution Control (b)	4,735
total	37,885

Annual Boiler Costs (a)

	$/$10^6$ Btu/heat input (a)
Boiler Fixed Costs	1.00
Pollution Control Fixed Costs (b)	0.14
Boiler O & M	1.43
Pollution Control O & M(b)	0.43
total	3.00(a)

Steam Costs (a)

	$/$10^6$ Btu of steam (c)
Boiler Less Fuel Cost	3.75
Fuel Cost (d)	0.63
total	4.38 (a)

(a) Third quarter 1979 dollars

(b) Includes systems for 90 percent SO_2 removal and particulate emission reduction to 0.03 lb/10^6 Btu

(c) Assumes 80 percent boiler efficiency

(d) Assumes $0.50/$10^6$ Btu fuel cost for Western power plants. This value should be adjusted for fuel costs for plant studied.

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4.4 Electrical Energy Penalty

The total capital cost of a retrofit system includes the capital cost of replacing the generating capacity lost because of the electric power requirements of the retrofit systems. This capital cost is $1,046 for each kilowat of capacity required by the retrofit systems.(1,3,4)

Sections 3.4 and 3.5 describe the techniques to be used for estimating retrofit electric power requirements for particulate and SO_2 control.

4.5 Other Costs Not Estimated

There are other capital and annualized costs involved in conjunction with retrofits that are not estimated in this document. This section identifies these cost elements and provides guidance on factoring these costs into decision making on best available retrofit technology (BART) determinations.

Other potential costs that are not included in the estimates of this document are identified as follows:

1. Cost of land
2. Cost of relocating facilities to make room for the retrofit systems
3. Cost of altering existing facilities to accommodate the retrofit systems
4. Cost of providing additional facilities for additional employees such as offices, locker rooms, etc.

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5. Cost of downtime for installing retrofits
6. Cost of stacks

The cost estimates of this document provide ample allowances for grading, excavating, piling, and for temporary construction facilities, etc.

In some cases, additional land may need to be purchased to make-up for the space needed for retrofit systems. Since the cost of this land can usually be recovered when the land is no longer needed, it is not included as a capital cost. It is recognized, however, that necessary funds would have to be made available for such land purchases and that annual costs would result. In the case of land for sludge disposal, it is assumed that once the land is used, it would not be possible to reclaim the land for any useful purpose. More study is needed to show that land used for sludge disposal can be reclaimed for future use.

Since most power plants have not been designed for future large retrofit systems, it is likely that most retrofit cases will involve relocation of some facilities such as shops, offices, or coal storage and handling systems. These capital costs will also cause an increase in annual costs.

Types of alterations that might be required to accommodate retrofit systems are the cost of relining stacks to compensate for more corrosive gas conditions or for reinforcing existing ductwork to compensate for changed flue gas pressure conditions, or costs for major changes to structures to accommodate NO_x combustion modifications. The costs of nominal alterations in conjunction with NO_x combustion modifications is included in the cost estimates of this document. Based on boiler manufacturer's advice, it may also be necessary to modify boiler pressure parts to control steam conditions to specifications. These costs are site-specific and are not estimated in this document.

The cost of downtime is also significant. The costs of this document assume that no additional downtime is required for retrofitting. The way downtime is avoided is by making all necessary changes to the existing system and by tieing in the retrofit systems during normal outages or during unscheduled outages attributable to factors other than retrofitting. As shown by Figure 3-8, these types of changes can be made during a 5-year period. If downtime is necessary, the following factors should be taken into account in assessing costs.

1. The cost of purchased power. Usually purchased power costs more than the cost of generating power within the system. However, at times the added cost of purchased power is reduced if the purchasing power system sells a like amount at the same price in conjunction with an exchange agreement.

2. The cost of power generation and distribution. Even if it is not necessary to purchase power from another system, downtime can involve significant additional costs. Downtime may make it necessary for a power system to generate power at a less efficient plant or at a plant firing more costly fuel. Power transmission losses also need to be considered. For the plants of Appendices A, B, and C, it is most likely that any downtime that would make it necessary to generate power elsewhere would involve significant additional fuel costs.

3. <u>Loss of Productivity</u>. When a steam generator is down, some labor, supplies, and services costs continue. Although these costs are small in comparison to other downtime costs, they should be considered in sufficient depth to classify them in their proper perspective.

Another cost that is not estimated in this document is the cost of transporting sludge from the liquor treatment system to the disposal site. This cost is estimated at $2 per ton per mile. Such costs are not estimated because it is not certain how far the sludge would have to be transported.

4.6 Cost of Derating

As discussed in Section 2-2.7, derating is usually an undesirable technique for reducing emissions. This is because there are usually more cost effective methods available. The costs of derating are very variable and are site specific. Consequently, no generalizations can be made on costs except to identify the potential cost elements.

For cases where electrical energy demand is increasing (this is almost always the situation) the generating capacity lost because of derating must be replaced. The cost of replacing generating capacity is given in Section 4.4 For cases where generating capacity is limited as compared with power system electrical demand, derating costs can be the same as the costs for downtime discussed in Section 4.5. For the most costly case it might be necessary to purchase power from another power system for several years until the power generating capacity lost by derating is replaced. However in most cases derating costs would not be this severe. For actual cases, additional studies are necessary to estiamte the costs of derating.

4.7 <u>Escalation</u>

The costs of this document are based on September 1979 dollars. Section 3.8 presents data on schedules for retrofitting which can be used in conjunction with economic data not given in this document to estimate the effect of escalation on capital costs.

4.7 REFERENCES

1. Wright, J., "Cost Analysis of Lime Based Flue Gas Desulfurization Systems for New 500 MW Utility Boilers", PEDCo Contract No. 68-02-2842, Assignment 25, January 1979.
2. Impact Analysis of Selected Control Levels for New Industrial Boilers, Preliminary Draft, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina June 1980.
3. EPA, "Electric Utility Steam Generating Units - Background Information for Proposed SO_2 Emission Standards". EPA-450/2-78-007a, August 1978.
4. EPA, "Electric Utility Steam Generating Units - Background Information for Proposed Particulate Matter, Emission Standards". EPA-450/2-78-006a, July 1978.